INJECTION WELL COMPLETION REPORT FORM 7520-9-- EAST CHERRY CREEK VALLEY WATER AND SANITATION DISTRICT WELL DI-2

Prepared for the Environmental Protection Agency

Prepared by Hydrokinetics, Inc.
November 21, 2016

TABLE OF CONTENTS

I. Geologic Information

1. Lithology and Stratigraphy

A. Geologic Information

B. Detailed Description of Injection Units

C. Formation Chemistry

D. Freshwater aquifers

II. Well Design and Construction

1-5. Casing and Tubing, cement, packer, centralizers, bottom hole completion, well stimulations.

III. Description of Surface Equipment

IV. Monitoring Systems

1. Pressure and temperature gauges, flow measurements.

V. Logging and Testing Results

1. Logging
2. Step Rate Testing (SRT)
3. Spinner Survey

VI. As-Built Diagrams

VII. Mechanical Integrity

VIII. Compatibility of Injectate with Injection Zone Fluids

IX. Corrective Action in Area of Review

X. Anticipated Maximum Flow Rate and Pressure

I. Geologic Information

1. Lithology and Stratigraphy

A. Geologic Information of Units Penetrated

A description of the rock units penetrated by the well is presented in the attached Lithologic Strip Log and in the Table 1 below.

Table 1. Geologic Description of Rock Units Penetrated by Well.

Period	Geologic Unit	Depth (ft.)	Thickness (ft.)	Description
Quaternary	Alluvium	0-60	60	Unconsolidated sand, silt, clay and gravel
Cretaceous	Arapahoe	60-616	556	Clear to tan sandstone and conglomerate, some shale, claystone and coal.
Cretaceous	Laramie-Fox Hills	616-1694	1078	Tan to gray sandstone, with dark shale, claystone and thin coal
Cretaceous	Pierre SH	1694-7142	5448	Gray to black shale, some sandstone layers
Cretaceous	Niobrara	7142-7494	352	Gray shale
Cretaceous	Fort Hays LS (in Niobrara)	7494-7523	29	White limestone interbedded with shale
Cretaceous	Greenhorn	7523-7828	305	Gray-black shale
Cretaceous	Dakota GP	7828-8324	496	Tan, gray, white sandstone, siltstone and shale
Cretaceous	J Sandstone (in Dakota GP)	7900-7964	64	Clear sandstone, with rare shale layers
Cretaceous	Dakota SS (in Dakota GP)	8200-8324	124	Clear to white sandstone, with rare shale layers
Jurassic	Morrison	8324-8450	126	Tan and maroon sandstone and shale
Jurassic	Entrada SS	8450-8634	184	Red to gray sandstone, some anhydrite and shale
Permian	Lykins	8634-9086	452	Red to black shale and siltstone, with anhydrite at base
Permian	Lyons	9086-9206	120	Clear, white to pink sandstone
Permian	L. Satanka	9206-9466	260	Red shale and sandstone with blue-white dolomite and anhydrite layers
Permian	Wolfcamp	9466-9594	128	Gray to red sandstone, shale, and anhydrite
Permian	Amazon	9594-9640	46	White limestone, dolomite and anhydrite
Permian	Council Grove	9640-9744	104	White to red limestone and dolomite with some sandstone, anhydrite and shale layers
Pennsylvanian	Admire	9744-9866	122	White to red limestone, sandstone, dolomite with some shale
Pennsylvanian	Virgil	9866-9944	78	White to red limestone, sandstone and anhydrite
Pennsylvanian	Missouri(an)	9944-10100	156	White to red sandstone, limestone, shale and anhydrite

Missouri unit also referred to as Missourian.

B. Detailed Description of Injection Units

Five geologic units were perforated and will received injected fluids. These are the Lyons, Wolfcamp/Amazon/Council Grove, Admire, Virgil and Missourian. With the approval of EPA personnel, the Wolfcamp, Amazon and Council Grove Formations were combined into one injection unit because they are adjacent to each other and have similar geology. A summary of these units and requested data are provided in Table 2. The requested depth, thickness, geologic age, and lithology are provided in Table 1. Listed fracture pressures are based on a fracture gradient of 0.75 psi/ft, per the EPA Area Permit at the step rate test transducer setting depth near the base of each zone. The formation fluid pressure listed is the pressure transducer reading near the base of the zone just prior to the step rate test on that zone. The wellhead pressure at the time of said testing varied slightly but was generally ±800 psi. For the Lyons Formation where no transducers were used during the SRT the formation pressure is the hydrostatic head plus 800 psi.

Table 2. Summary of Downhole Data for Injection Units

Injection Unit	**Lyons**	**Wolfcamp/Amazon/ Council Grove**	**Admire**	**Virgil**	**Missourian**
Formation Fluid Pressure (psi)	4760	4980	4980	5130	5130
Avg. Porosity (percent)	2-7	1-5	1-10	1-5	2-9
Estimated Permeability (mD)	5-10	5-10	5-10	1-5	1-5
Fracture Pressure (psi)	6860	7205	7350	7430	7690
Bottom Hole Temperature (F)	NA	NA	NA	NA	265
Bottom Hole Pressure (psi)	NA	NA	NA	NA	4370

C. Formation Chemistry

After the slotted casing was set, and the swell packers allowed to swell for two weeks, each zone was swabbed (or flowed under artesian pressure) until the specific conductivity of the water removed from the unit was stable for at least three consecutive swab runs. At this time, the sample was considered to be representative of the formation fluid. At that point, a sample was secured and tested in the laboratory for TDS, pH, specific conductivity and specific gravity as required by the permit. Although not required, we tested the samples for additional inorganics, including some major cations, anion, and some metals. The original laboratory results are attached. The water quality data for the injection zones are summarized below in Table 3. Note that the Virgil and Missourian zones were swabbed dry and samples could not be obtained.

Table 3. Water Quality Summary in Injection Units, Well DI-2 (August, 2016).

Formation	Lyons	Wolfcamp/Amazon/ Council Grove	Virgil	Admire	Missourian	units
Barium	2020	223	No sample	2070	No sample	ug/l
Calcium	4100000	327000		5030000		ug/l
Iron	65900	24400		118000		ug/l
Magnesium	338000	47500		354000		ug/l
Manganese	2050	605		2470		ug/l
Potassium	651000	340000		501000		ug/l
Silicon	47900	51000		37300		ug/l
Sodium	17300000	5230000		20200000		ug/l
Strontium	17500	8670		14600		ug/l
Bicarbonate as HCO3	593	1200		818		mg/l
Carbonate as CO3	<5.0	<5.0		<5.0		mg/l
Chloride	43700	8430		43900		mg/l
Fluoride	<10	8.1		<50		mg/l
Nitrogen, Nitrate	2.9	5.5		<5.0		mg/l
Phosphate, Ortho	<5.0	<2.5		<25		mg/l
Redox Potential vs H2	364	376		365		mv
Silica	102	109		79.8		mg/l
Total Dissolved Solids	59000	16900		76500		mg/l
Specific Conductivity	91000	24000		91500		umhos/cm
Specific Gravity	1.0505	1.0136		1.0544		
Sulfate	965	2300		1580		mg/l
Sulfide	<0.50	<0.50		<0.50		mg/l
pH	6.12	6.49		6.52		

D. Freshwater aquifers

There are three freshwater (drinking-water) aquifers penetrated by well DI-2. This is based on our experience with numerous wells in the Denver basin and Table 2.4 in the EPA Injection Well Permit for well DI-1. They are the alluvium, Arapahoe and Laramie-Fox Hills aquifers. The depth to the lowermost freshwater aquifer is 1694 feet. Data on these aquifers including estimated average TDS values are presented in Table 4.

Table 4. Freshwater Aquifers.

Period	Geologic Unit	Depth (ft. bgl)	Estimated TDS (ppm)	Thickness (ft.)	Description
Quaternary	Alluvium	0-60	750	60	Unconsolidated sand, silt, clay and gravel
Cretaceous	Arapahoe	60-616	800	556	Clear to tan sandstone and conglomerate, some shale, claystone and coal.
Cretaceous	Laramie-Fox Hills	616-1694	550	1078	Tan to gray sandstone, with dark shale, claystone and thin coal

II. Well Design and Construction

1. Casing and Tubing

Surface and long string casing and liner were installed in well DI-2. Swell packers were installed on the liner between zones to keep the injection zones hydraulically separated during testing. A permanent packer was then set inside the long string on the 5.5 inch production tubing. The casing, liner and tubing data are provide in Table 5 and in the As-Built well diagram. The As Built wellhead diagram is also attached.

The borehole diameters were: 14.75 inch from ground level to 1743 feet, 9.875 inch from 1743 to 9071 feet and 6.25 inch from 9071 to 10,100 feet–all from ground level.

Table 5. Casing, Liner, Tubing Data.

	Surface Casing	**Long String Casing**	**Liner (plain and slotted)**	**Production Tubing**
Material	steel	steel	steel	steel
Diameter (in.)	10.75	7.625	4.5	5.5
Grade	J55 STC	P110 HC R3 SMLS LTC	API 5CT, 0.060 in. Slot	P110 DTS4 R3 with internal coating TK-805
Weight (ppf)	40.5	26.4	11.6	20
Setting Depth (ft. bgl)	0-1760	0-9088	9043-10100	0-9030

2. Cement

All cement was placed using the Halliburton method. Cementing data is summarized in Table 6.

Table 6. Cementing Data.

	Depth (ft. bgl)	Cement Type	Weight (lb/gal)	Amount (sacks)
Long String, 1st stage	7714-9088	ExpandaCem	13.8	302
Long String, 2nd stage	7714-GL	ElastiCem HalCem	13.2 15.8	1900 90
Surface Casing	1760-GL	Swift Cement Swift Cement	13.5 14.2	670 110

3. Packers.

Swell Packers (4.5 inch x 6.25 inch Tendeka SwellRight) were set on the 4.5 inch liner between each injection zone as shown on the As Built well diagram.

A permanent packer (Landeow 13 Chrome, 7.625 inch) was set on the end of the 5.5 inch production tubing at 9030 feet. It is engaged against the 7.625 inch casing. Water mixed with 55 gallons of Endura CI811 Packer Fluid and 10 gallons of Novacide 1025 Biocide was place in the casing-tubing annulus.

4. Centralizers

On the 10.75 inch surface casing, 39 Davis steel centralizers were installed (one approximately every 45 feet) from 60 to 1743 feet. Two Davis cement baskets were installed at 80 and 120 feet.

73 Davis steel centralizers were installed on the 7.625 inch long string casing (one approximately every 100 feet) from 1743 to 9071 feet.

5. Bottom Hole Completions

Not applicable.

6. Well Stimulations

Each zone was developed by installing a packer at the top of the zone and a plug at the base of the zone, pumping in 15% strength hydrochloric acid (at 2 to 4 bbl/min and 1000 to 1500 psi at the wellhead) which was followed by fresh water, as follows:

Lyons (8-16-16)

1000 gallons of HCL with 40 gallons of WellKlean enhancer/corrosion inhibitor was pumped into the zone followed by 100 bbls of fresh water.

Missourian (8-18-16)

1000 gallons of HCL with 40 gallons of WellKlean enhancer/corrosion inhibitor was pumped into the zone followed by 100 bbls of fresh water.

Virgil (8-20-16)

1000 gallons of HCL with 40 gallons of WellKlean enhancer/corrosion inhibitor was pumped into the zone followed by 150 bbls of fresh water.

Admire (8-23-16)

1000 gallons of HCL with 40 gallons of WellKlean enhancer/corrosion inhibitor was pumped into the zone followed by 100 bbls of fresh water.

Council Grove (8-24-16)

1000 gallons of HCL with 40 gallons of WellKlean enhancer/corrosion inhibitor was pumped into the zone followed by 100 bbls of fresh water.

Wolfcamp/Amazon (8-26-16)

2000 gallons of HCL with 80 gallons of WellKlean enhancer/corrosion inhibitor was pumped into the zone followed by 100 bbls of fresh water.

III. Description of Surface Equipment

In general, water coming from a fresh water wellfield will be pumped to the treatment plant to reduce the total dissolved solids in the water. In the treatment plant the water is first filtered, run through a reverse osmosis membrane (module), then run through a second brine concentration module. The brine remaining is then pumped into the two injection wells. (See attached filtration sketch and well location map with DI-1 and DI-2 well locations). Prior to injection, a scale inhibitor, sodium hypochlorite, sodium hydroxide and hydrochloric acid will be added to the brine. The purpose of introducing these chemicals into the brine is to minimize plugging of well perforations dowhole. The surface equipment for Well DI-2 has not yet been installed.

IV. Monitoring Systems

1. Pressure and temperature gauges, flow meters.

The flowpath of the water/brine as it flows from the wellfield to the injection well (along with flowmeter locations) is shown in the diagrams presented in Section III above.

Two recording pressure transducers will be installed in the injection inflow piping–one at the injection pump and one at the wellhead. One recording transducer will be installed in the annulus between the 5.5 inch tubing and 7.625 inch casing at the wellhead. A recording temperature gauge will also be installed at the wellhead in the injection inflow piping. All transducers and the temperature gauge will record readings every minute.

A recording flow meter will be installed in the inflow pipeline between the injection pump and the well which will record readings every minute. A manual pressure gauge will also be installed in the tubing-casing annulus at the wellhead. It will be read and recorded by hand if the pressure transducer fails.

V. Logging and Testing Results

1. Logging

Six geophysical well log surveys were performed on the well. All are attached in digital format. As requested, we will provide paper copies of the two cement bond logs. Due to caving conditions in the borehole, after several logging attempts, we were unable to obtain the open hole resistivity/density etc. log in the longstring hole between 1743 and 9071 feet. Instead, as allowed by the EPA (email of 6-27-16), we conducted a pulsed neutron, porosity log for the cased hole in this zone. Attached are the following logs:

Spectral density/resistivity log (with caliper, gamma, porosity, SP, density, and resistivity surveys) for surface open hole.

Cement bond, gamma, temperature, casing collar locator log for surface casing.

Spectral density/resistivity log (with caliper, gamma, porosity, SP, density and resistivity surveys) for production zone open hole.

Cement bond, gamma, casing collar locator log for longstring 7.625 inch casing.

Pulsed neutron, gamma, porosity, casing collar locator log for longstring 7.625 inch casing.

Temperature, gamma, casing collar locator log for the entire completed well.

As drilling proceeded, vertical deviation surveys were taken on a regular basis. The maximum deviation was 2.0 degrees at 6998 feet.

The vertical deviation surveys are presented in Table 7.

Table 7. Well DI-2 Vertical Deviation Survey Records

Depth (ft bgl)	Deviation (deg)	Depth (ft bgl)	Deviation (deg)
253	0.4	5295	0.4
377	0.1	6051	0.6
936	0.4	6239	0.2
1407	0.2	6428	0.5
1654	0.1	6616	1.6
1881	0.2	6998	2.0
2067	0.0	7186	0.5
2259	0.0	7376	0.5
2448	0.2	7565	0.2
2637	0.2	7755	0.2
2827	0.2	7944	0.3
3964	0.4	8133	0.5
4154	0.5	8323	0.6
4343	0.8	8516	0.4
4532	0.8	8638	0.4
4722	1.5	8705	0.6
4912	1.6	8893	0.9
5102	1.0		

2. Step Rate Testing (SRT)

Well DI-2 was drilled, constructed and tested between June 17, 2016 and September 7, 2016. The testing on the well included performing step rate tests (SRT) on each individual slotted zone and a step rate test on the entire well (all slotted zones).

There are five slotted zones in Well DI-2, including, from top to bottom:

Lyons Formation

Wolfcamp/Amazon/Council Grove Formations (as approved by EPA)

Admire Formation

Virgil Formation

Missourian Formation.

Each SRT was conducted using the EPA's "Step Rate Test Procedure" with seven, 30 minutes steps per test. After analyzing the geologic and electric logs, we decided to isolate the Council Grove formation by installing a swell packer between the Amazon and Council Grove formations. This was done to obtain better acid stimulation in all three formations in the zone.

It is important to note that this well was overpressured during some of the drilling and all of the completion/testing work. This overpressure situation (600 to 925 psi at ground level) had to be controlled to allow work to continue on the well. To reduce the surface pressure to a manageable level, or "kill" the well, weighted fluid was added multiple times between July 3, 2016 (when the overpressure first occurred) and September 7, 2016. The fluid added was heavy salt brine (sodium chloride and calcium chloride) with total dissolved solids ranging from 60,000 to over 300,000 mg/l. These fluids were prepared to be as dense as possible, and therefore very close to the saturation point.

Salt brine was generally added in the early morning because the well would usually become unbalanced when it was left overnight. During testing, the brine was added to "kill" the well every day or at times, every other day (not including Sundays when the well was idle).

In total, we added 159,936 gallons of brine to the well between July 4, 2016 and September 7, 2016. This volume of brine was substantial and very likely affected the results of the step rate tests.

We set two pressure transducers in the bottom of each zone (except the Lyons) prior to running each SRT. As allowed by the EPA (email of August 17,2016) we were not able to install transducers during the Lyons formation SRT so we only have wellhead pressure/time/flow data for this SRT. In each SRT the time/pressure results of the two transducers were virtually identical. For the sake of simplicity, only one set of pressure is plotted here. We also recorded the pressure at the wellhead as each test proceeded. In this way we could look at the surface pressure, formation pressure (FP), and define actual friction loss for each step of each test after the transducers were recovered from the well after the SRT.

Attached are one set of six graphs showing the surface pressure and flow rate graphs recorded by Basic Energy Services for each SRT and a second set of five graphs showing time vs formation pressure (transducer data). On the time vs formation pressure graph for All Zones, which was run through the 5.5 inch coated production tubing, we have also listed the actual friction loss for each step. Also attached are five files in XL format which include time, pressure, and temperature data for each SRT when transducers were used. Friction losses for individual zone tests are not listed because these tests were conducted using older, non-coated, 3.5 inch rig tubing.

The data and graphs show the following:

The Lyons and the Wolfcamp/Amazon SRTs show pressure increasing steadily with each increase in flow rate as expected for each step.

The Council Groves SRT FP graph has 3 pressure anomalies. Pressure drops during steps 5 and 6 and an unexpected pressure gain during step 7.

The Admire SRT FP graph also has 3 pressure irregularities, which include a sudden pressure drop, then rise in step 3, and an abrupt pressure gain in step 7.

The Virgil SRT FP graph shows similar unanticipated drops and rises in pressure in steps 4, 6 and 7.

The Missourian SRT FP graph has one substantial pressure drop in step 3.

The All Zones SRT FP graph proceeded as expected for the first 5 steps, after which we see a slight pressure drop.

It appears that these pressure anomalies listed above are caused by salt deposits remaining in the subsurface. These salt deposits could be in the liner slots, in the annulus between the borehole and the liner and in the formation itself. As mentioned previously, 159,936 gallons of dense salt brine was added to the well to control the flow at the wellhead. None of this salt was retrieved. Most of this brine was added during the well stimulation and testing phases.

Some of this salt appears to have precipitated out downhole and is being pushed around and/or dissolved in the liner slots or formation. There were several occasions when we pulled the packer/plug tools from the hole (between SRTs) to find one or both completely encrusted with hard salt crystal deposits. A typical SRT was run by arriving at the site in the morning to find that the well became overpressured overnight, adding brine to “kill” the well, then running the SRT with fresh water. The fresh cold water was pumped down the tubing and out into the formation over the course of the SRT (3.5 hours). The drop in downhole temperature due to the cold water running into the formation causes the salt to precipitate out, however, the low salinity of the fresh water causes the salt deposits to dissolve downhole. The interaction of these two processes, which changes with time and location, appears to be what is causing the unexpected pressure fluctuations during the SRTs.

It does not appear we are seeing any fracturing, especially in the All Zones SRT because we should be well below the fracture gradient. Per the EPA area permit, the estimated fracture gradient for the slotted zones is between 0.75 and 0.8 psi/ft (page C-1, EPA permit). Using a fracture gradient of 0.75, and a transducer setting of 10,080 feet in the All Zones SRT, the fracture pressure would be 7560 psi. During the All Zones SRT, the highest formation pressure was approximately 5740 psi, about 1820 psi lower than the fracture pressure. The flattening of the formation pressure curve in the final 2 to 3 steps in the All Zones SRT is likely being caused by the high volume of fresh water reaching deep into the formations and dissolving salt deposits that precipitated in the formation and which impeded flow in the early steps.

Therefore, we request a maximum allowable injection pressure (at the wellhead) of 4000psi which corresponds to a formation pressure of about 5700 psi at 10,080 feet. At this wellhead pressure, at 50 bpm, the friction loss is 2646 psi, which is 66% of the wellhead pressure. Also, at a wellhead pressure of 4000 psi, the pressure increase on the formation (from pre test level to the end of the 50 bpm step) is only 350 psi.

3. Spinner Survey

As required by the EPA Area permit, we conducted a spinner survey on the Wolfcamp/Amazon/Council Grove zone to define the percentage of injectate flow that each of the three formations received during injection. A spinner tool was run up and down multiple times through the section of interest as 10 bpm of fresh water was being pumped into the well by Reliance Oilfield Services. The Reliance report, attached, concludes that approximately 49% of the fluid was received by the Wolfcamp, 44% by the Amazon and 6% by the Council Grove formation.

VI. As-Built Diagrams

The As-Built diagrams of the well and wellhead are attached.

VII. Mechanical Integrity

The mechanical integrity of the well has been demonstrated by performing the MIT test on the well on 9-23-16. The results are attached.

VIII. Compatibility of Injectate with Injection Zone Fluids

The brine to be injected into well DI-2 is the same water that is now being injected into, and has been injected into the DI-1 well over the past 5 years. The two wells are both injecting brine into approximately the same zones. Because we have experienced no plugging problems with the DI-1 well, we anticipate the brine injectate is similarly compatible to the formation water in DI-2.

IX. Corrective Action in Area of Review

There are no defective wells requiring or undergoing corrective action in the area of review.

X. Anticipated Maximum Flow Rate and Pressure

We anticipate injecting at approximately 50 to 1000 gallons per minute intermittently throughout any given year. It is possible that injection rates may exceed the 1000 gpm estimate depending on logistical pumping needs. The wellhead pressure during the life of the well will likely increase with time as the well plugs with precipitates and bacteria. We may clean the well every few years to maximize flow through the perforations. The expected wellhead pressure during injection will generally be below 2500 psi for the first several years. The maximum wellhead pressure will not exceed the MAIP approved by the EPA.